APPENDIX C:

POTENTIAL COST SAVINGS FROM ELECTRICITY
COMPETITION:

BEST PRACTICES ANALYSIS

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POTENTIAL COST SAVINGS FROM ELECTRICITY COMPETITION

Summary:

This paper quantifies potential savings opportunities in four areas: cost reduction (including fuel procurement, non-fuel operation and maintenance (O&M) expenses, and administrative and general (A&G) expenses), dispatch efficiency, improved capital utilization, and savings in capital additions. Table 1 summarizes these potential savings.

Table 1
Summary of Cost Savings Potential from Competition

Source of Savings	Potential Size of Benefit (billions of $)
Cost Reduction (Fuel, non-fuel O&M, A&G)	$24.6
Dispatch Efficiency	$0.6
Improved Capital Utilization	$0.8 to $2.6
Reduced Capital Additions	$0.3 to $3.8
TOTAL	$26.3-31.6

Several sources of important additional savings are not considered in this paper.

First, as pricing becomes more efficient, load shape adjustments from consumers on the demand side of the meter can reduce the need to add expensive new capacity that would otherwise be necessary to meet peak demands of only a few hours duration per year. A recent study of the New York State power pool suggests that savings in that one area alone could reach $660 million annually by 2010.

Second, our cost analysis assumes that regulators and firms would not repeat past mistakes with respect to capacity planning, choice of technology, or project management that have raised the cost of power to consumers. While regulators have undoubtedly learned from past events, future regulation is unlikely to be perfect.

Finally, experience in other sectors suggests that competition will lead to the creation of new product combinations with greater economic value to consumers. Our estimates do not reflect this benefit at all.

The remainder of this paper provides detail on the four categories of potential savings summarized in Table 1.

1. Fuel Costs, Non-Fuel Operation and Maintenance (O&M) Costs, and Administrative and
General (A&G) Costs

Fuel Costs, Non-Fuel O&M Costs, and A&G Costs, which together accounted for roughly $94
billion in reported utility cost in 1995, largely reflect the current operations of electric utilities.
(Note: A portion of A&G costs also reflect historical operations to the extent that pension
liabilities have not been funded on a current basis.)

Information reported in standard industry filings suggests a wide range of cost experience across
reporting units and companies. These data can be used to gain insight into opportunities for cost
reduction. Our approach here is to estimate the value of bringing the cost performance of the
entire industry up to the standard already demonstrated by top industry performers -- represented
in this paper as the average of the top quartile of reported performance.

Some of the difference in cost experience clearly reflects circumstances that will not be changed
by the advent of competition. For example, coal prices differ according to the distance from low-
cost coal supplies; heat rates reflect the vintage, type, scale, and operating rate of plants and
pollution control requirements; and distribution costs are systematically related to the density of
customers on a system.   To account for such factors, the reported data is stratified along key
dimensions prior to developing the quartile analysis. Stratification (details reported in Appendix)
narrows the range of cost variation, but significant differences remain, as reported in Table 2.

Table 2
Cost-Reduction Opportunities

Category	Potential Savings (billions of 1996 dollars)
Fuel Acquisition	$6.7
Heat Rates	$0.9
Non-fuel Operation and Maintenance	$11.0
Administrative and General	$6.0
TOTAL	$24.6

The reported total of $24.6 billion in cost-saving potential could either underestimate or
overestimate actual cost reduction opportunities.   On the underestimation side, top quartile
performance under regulation may understate achievable efficiencies under competition as even
the best current performers re-engineer and rethink their activities. Moreover, the lack of data for
existing non-utility generators, who are widely believed to be among the most cost-effective
operators, could lead to some underestimate of even the current state-of-the-art efficiencies. On
the overestimation side, the stratification underlying the quartiles reported in Table 2 for fuel and
O&M costs may fail to account for all sources of irreducible cost differences. Moreover, the
portion of the variation in cost across plants that reflects contract cycles for fuel and other inputs

could be expected to narrow over time independent of the advent of competition.

2. Dispatch Efficiencies

Competition is likely to result in improved dispatch efficiencies. The advent of competition will shift the market from a "shared savings" paradigm to one in which the party that identifies a cost-effective trade can reap the benefits, providing dispatch efficiencies beyond those that might result from wholesale competition alone. Analyses using the Policy Office Electricity Modeling System (POEMS) suggest that dispatch efficiencies resulting from retail competition can reduce aggregate system fuel costs by approximately $600 million relative to a scenario reflecting a continued cost-of-service regime.

3. More Efficient Utilization of Capital.

The generation, transmission, and distribution of electricity are among the most capital-intensive activities in the U.S. Yet, the relatively inflexible price signals provided to consumers under traditional cost-of-service regulation have resulted in relatively poor utilization of our substantial investment in electricity-related capital. Retail competition will allow electricity markets to emulate the experience of airlines and communications providers in implementing load-sensitive pricing regimes (such as 5 cents per minute calls on Sundays), allowing the additional use of electricity in price sensitive applications during off-peak and off-season periods.

Ideally, the gains from more efficient capital utilization would be calculated separately for each load segment in each season. However, absent estimates of segment-specific demand responses to price variation, the impacts of competition on average prices can be used to develop a rough estimate of capital utilization benefits. Model results and recent experience with restructuring at the state level suggest that average delivered prices in a restructured industry will average 6 to 9 mills (9 to 13 percent) lower than prices projected under continued cost-of-service regulation, depending upon what provisions are made for stranded cost recovery. Using an estimate of -.1 to -.2 for the price elasticity (the percentage change in demand resulting from a 1% increase in price), the 9 to 13 percent price drop translates into an increase of between 0.9 and 2.6 percent in electricity sales.

The net welfare benefit from these extra sales includes two components. First, there is additional "consumer surplus" which reflects the extent to which the value of the extra electricity to buyers exceeds its price. Second, since extra sales under load-sensitive market pricing do not increase transmission or distribution system costs or stranded costs, any transmission, distribution, or stranded cost charges on these sales are also a net welfare gain. In 1995, the national average for transmission and distribution was 2.38 cents per kilowatt-hour. For a level of baseline demand of 3,250 billion kilowatthours, the estimated net welfare gain from more intensive capital utilization is estimated to fall between $820 million and $2.6 billion.

It is important to note that the estimates in this section focus narrowly on the more efficient use of the baseline capital stock and do not include an estimate of the substantial benefit of more nimble pricing in curtailing peaks that often necessitate the addition of expensive new capacity.

4. Reduced Capital Costs at Existing Plants

Capital additions at existing plants are another area where available data suggest a considerable range of experience across utilities.   However, the analysis of such additions can be quite complex. First, a considerable portion of the observed variation in the cost of capital additions per unit of capacity can often result from environmental or nuclear regulatory decisions or determinations affecting specific units that would not be sensitive to the shift to a more competitive regime.   Second, capital additions occur at irregularly spaced intervals, and many plants will have no significant capital additions in a particular year.

To address the issue of irregularly-spaced capital additions, we focused on average capital additions over a decade rather than additions in a single year. Over the 1985 to 1995 period, reported capital additions at existing power plants averaged approximately $6.3 billion per year, with average additions of $3.1 billion at nuclear plants, $2.6 billion at coal fired plants, and $0.6 billion at oil and gas steam plants.

For present purposes, the most interesting comparisons can be made within the set of coal plants commissioned after 1965 that were operating without scrubbers or NOx controls at the end of the sample period. Capital additions at these plants would not reflect the costs of repowering, emissions control requirements, or nuclear regulation.   Assuming that the average of the top quartile of reporting units reflects the typical standard of performance in competitive markets, annual cost savings opportunities relative to actual reported costs for capacity additions within this relatively homogeneous subgroup of coal plants are estimated at $274 million out of $468 million.   The application of quartile analysis to the capital additions data for the stratified sample of all plants of all fuel types suggests an overall potential savings of $3.8 billion, but this is likely to be a significant overestimate for reasons outlined above. The real potential for cost-savings in capital additions likely lies in the lower portion of the range of $0.3 to $3.8 billion.